RESULTS OF OPERATIONS

Revenues

	Three months ended June 30				Six months ended June 30			
(Canadian dollars in millions)	2011	2010	$ Change	% Change	2011	2010	$ Change	% Change
Transmission	337	306	31	10	688	626	62	10
Distribution	915	842	73	9	2,008	1,825	183	10
Other	16	17	(1)	(6)	32	33	(1)	(3)
	1,268	1,165	103	9	2,728	2,484	244	10
Average Ontario 60-minute peak demand (MW)[1]	20,519	20,610	(91)	-	21,138	20,772	366	2
Distribution - units distributed to customers (TWh)[1]	6.5	6.4	0.1	2	14.8	14.4	0.4	3

[1] System-related statistics are preliminary

The demand for electricity generally follows normal weather-related variations, and, therefore, our energy-related revenues, all other things being equal, will tend to be higher in the first and third quarters than in the second and fourth quarters.

Transmission

Transmission revenues predominantly consist of our transmission tariff, which is based on the monthly peak demand for electricity across our high-voltage network. The tariff is designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate the maximum expected demand. Demand is influenced by weather and economic conditions. Transmission revenues also include minor amounts of ancillary revenues which are primarily attributable to maintenance services provided to generators and to secondary use of our land rights-of-way.

Our transmission revenues were higher by $31 million, or 10%, in the second quarter, and by $62 million, or 10%, in the first six months compared to the same periods last year. These increases were primarily due to higher tariff revenues of $21 million in the second quarter and $43 million year-to-date resulting from a December 23, 2010 Ontario Energy Board (OEB) decision on the 2011 and 2012 transmission rate application by our subsidiary, Hydro One Networks Inc. (Hydro One Networks). The decision followed extensive oral and written reviews of evidence we submitted for the funding necessary to support our system requirements. The resulting rates, which were effective January 1, 2011, will support our investments to address aging critical infrastructure, supply mix objectives for generation including off-coal initiatives, and the initiation of investments in support of the Green Energy Act (GEA).

Due to cooler weather experienced in the second quarter, we experienced a lower average monthly peak demand compared to the prior year, resulting in lower transmission revenues of $1 million in the second quarter compared to 2010. Increased revenue of $11 million on a year-to-date basis resulted from a higher average monthly peak demand in the first quarter of the year. Among other factors, weather was generally colder over the winter months compared to the same period in the prior year.

We also experienced higher transmission-related ancillary revenues of approximately $11 million in the second quarter and $8 million on a year-to-date basis resulting from increased export service and external revenues approved as part of the OEB rate decision. Export service and net external revenues received in excess of approved levels are recorded in a regulatory deferral account and are not recorded as revenue.

Distribution

Distribution revenues include our distribution tariff, as well as amounts to recover the cost of purchased power used by our customers. Accordingly, our distribution revenues are influenced by the amount of electricity we distribute, the cost of purchased power and our approved distribution tariffs. Distribution revenues also include a minor amount of ancillary distribution services revenues, such as fees related to the use of our poles by the telecommunications and cable television industries, and miscellaneous charges such as those for late payments.

Distribution revenues increased by $73 million, or 9%, in the second quarter, and by $183 million, or 10%, in the first six months compared to the same periods last year. This increase includes the recovery of higher purchased power costs of $45 million in the second quarter and $109 million in the first six months, as described below under "Purchased Power."

After considering purchased power costs, increases in revenue reflect two OEB decisions on the distribution tariff rates of our subsidiary, Hydro One Networks. On April 9, 2010, the OEB approved new tariff rates effective May 1, 2010 and on December 21, 2010, the OEB approved new tariff rates effective January 1, 2011. Both OEB decisions followed extensive written and oral reviews of the evidence we submitted for the maintenance and investment requirements of our distribution system, including those necessary to support renewable distributed generation. The combined impact of these decisions was an increase in distribution revenues of $24 million during the second quarter and $70 million in the first six months. These tariff rate increases enable the safe and reliable delivery of electricity to our customers throughout Ontario. The development of the Smart Grid is necessary to ensure the future of our system by facilitating the connection of new generation. We also experienced higher ancillary distribution revenues of approximately $5 million in both the second quarter and the year-to-date period as a result of these OEB decisions.

Also contributing to increased tariff revenues was higher energy consumption. Energy consumption was slightly higher in the second quarter than in the prior year resulting in higher revenues of $1 million. On a year-to-date basis, higher consumption resulted in an increase in distribution revenue of $7 million resulting primarily from the colder winter.

These increases were partially offset by a revenue reduction of $2 million in the quarter and $8 million on a year-to-date basis associated with the full recovery of a distribution-related regulatory account effective April 30, 2010.

Purchased Power

Purchased power costs incurred by our Distribution Business represent the cost of electricity delivered to customers within our distribution service territory and comprise the wholesale commodity cost of energy, the Independent Electricity System Operator's (IESO's) wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy for certain low-volume and designated customers is based on the OEB's Regulated Price Plan (RPP), which consists of a two-tiered pricing structure with threshold amounts and a separate pricing structure for RPP customers on time-of-use billing, both of which are adjusted twice annually. We began transitioning our RPP customers to time-of-use billing May 1, 2010 and the majority of our RPP customers are now on time-of-use billing. Customers who are not eligible for the RPP pay the market price for electricity, adjusted for the difference between market prices and the prices paid to generators under the *Electricity Restructuring Act, 2004*. A summary of the RPP for the reporting and comparative periods is provided below.

Summary of RPP

RPP – Tiered	Tier Threshold (kWh/month)		Tier Rates (cents/kWh)	
Effective Date	**Residential**	**Non-Residential**	**First Tier**	**Second Tier**
November 1, 2009	1,000	750	5.8	6.7
May 1, 2010	600	750	6.5	7.5
November 1, 2010	1,000	750	6.4	7.4
May 1, 2011	600	750	6.8	7.9

RPP Time-of-Use	Rates (cents/kWh)		
Effective Date	**On-Peak**	**Mid-Peak**	**Off-Peak**
May 1, 2010	9.9	8.0	5.3
November 1, 2010	9.9	8.1	5.1
May 1, 2011	10.7	8.9	5.9

Purchased power costs increased in 2011 by $45 million, or 8%, to $587 million in the second quarter and by $109 million, or 9% to $1,306 million in the first six months compared to the same periods last year. The increases in our purchased power costs were primarily due to: the impact of changes in the OEB's RPP rates for residential and other eligible customers of $21 million in the second quarter and $47 million in the year-to-date period; higher purchased power costs for customers who are not eligible for the RPP of $12 million in the quarter and $22 million in the first six months of the year; increased transmission charges due to the OEB's transmission rate decisions effective January 1, 2011 of $5 million for the quarter and $12 million for the year-to-date period; and the impact of higher charges levied by the IESO of $1 million in both the second

quarter and for the first six months of 2011. In addition, there was higher demand for electricity of $6 million in the quarter and $27 million in the year-to-date period

Operation, Maintenance and Administration

Our operation, maintenance and administration costs consist of labour, material, equipment and purchased services which support the operation and maintenance of the transmission and distribution systems. Also included in these costs are property taxes and payments in lieu thereof on our transmission and distribution lines, stations and buildings.

Operation, maintenance and administration costs for each of our three business segments were as follows:

	Three months ended June 30				Six months ended June 30			
(Canadian dollars in millions)	2011	2010	$ Change	% Change	2011	2010	$ Change	% Change
Transmission	104	103	1	1	210	210	-	-
Distribution	155	148	7	5	297	285	12	4
Other	16	15	1	7	30	29	1	3
	275	266	9	3	537	524	13	2

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way increased marginally by $1 million, or 1%, in the quarter and were unchanged on a year-to-date basis, compared to the same periods last year. Within our work programs, we continued to invest in the safe and reliable operation of our transmission system that spans Ontario. Our work program requirements were higher by $6 million in the quarter and by $9 million on a year-to-date basis compared to the same periods last year. These requirements were mainly associated with higher requirements for demand-based corrective station maintenance for power equipment and higher demand maintenance requirements related to the fire at our Richview Transformer Station. Our crews worked tirelessly to rebuild and in-service the impacted aging transformers to ensure adequate supply to critical local distribution companies. In addition, an increased focus on our environmental on-site oil leak reduction program reflects our priority on environmental stewardship. In addition, for the six-month period, we experienced higher forestry program expenditures as resources were utilized early in the year to advance the program due to favourable weather conditions. Expenditures in support of our transmission system decreased by $5 million and by $9 million, in the second quarter and first six months, respectively. During both periods, we incurred lower expenditures related to reduced telecom costs from lower long distance rates associated with leveraging broader public sector rates on voice domain and lower data usage.

Distribution

Operation, maintenance and administration expenditures incurred to sustain our low-voltage distribution system increased by $7 million, or 5%, in the quarter and by $12 million, or 4%, on a year-to-date basis, compared to the respective periods last year. Our work program expenditures were higher by $5 million in the quarter and by $4 million on a year-to-date basis compared to the same periods last year. In both the quarter and the year-to-date periods, we experienced increased power restoration expenditures associated with higher storm activity. This year we have experienced two severe storms compared to one last year. In addition, we experienced increased requirements associated with unplanned system changes to implement OEB code amendments impacting the billing system. These increased expenditures were partially offset in both periods by lower forestry expenditures resulting from a temporary re-direction of work to our transmission forestry program and to storm restoration work. Expenditures in support of our distribution system increased by $2 million the quarter and $8 million on a year-to-date basis primarily due to higher costs required to support operation, partly offset by lower telecom costs.

Depreciation and Amortization

Depreciation and amortization expense increased by $7 million, or 5%, to $151 million in the second quarter and by $12 million, or 4%, to $295 million in the first six months compared to the same periods last year. These increases were mainly attributable to higher depreciation of approximately $6 million in the quarter and $14 million in the first six months of the year related to our placement of new assets in service, consistent with our ongoing capital work program. A further increase of approximately $3 million in the quarter and $5 million for the year-to-date period resulted from increased fixed asset removal requirements associated with storm damage and our capital project work. Amortization of regulatory and other

assets declined by $2 million in the quarter and $7 million in the first half of the year, mainly due to the full recovery of a distribution regulatory account during the second quarter of last year.

Financing Charges

Financing charges decreased by $2 million, or 2%, to $86 million in the second quarter and by $3 million, or 2%, to $170 million for the year-to-date period compared to the prior year. The decreases were primarily due to higher capitalized interest of $2 million and $4 million in the first quarter and first six months, respectively, reflecting higher levels of construction-in-progress consistent with our growing capital program. For the year-to-date period, higher income of $2 million primarily relating to our long-term investment also contributed to the reduction in our net financing charges. The reductions in the first six months were partially offset by an increase of $3 million associated with a higher average level of debt, which was partially offset by a lower average effective interest rate.

Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes increased by $7 million, or 35%, to $27 million in the second quarter and by $33 million, or 100%, to $66 million on a year-to-date basis, compared to last year. These increases were primarily due to net temporary differences including those related to capital cost allowance versus depreciation on our fixed assets. Higher pre-tax income in both periods, partially offset by a reduction in the statutory tax rate from 31.00% to 28.25% also contributed to the increase in both periods.

Net Income

Net income of $142 million in the second quarter and $354 million year-to-date was higher than our comparable 2010 results by $37 million, or 35%, and by $80 million, or 29%, respectively. Higher net income reflected OEB rate decisions that allowed for the recovery of assets from prior years which are now in-service and a higher rate of return for the electricity industry, based on the OEB's standard formula. New assets in service include new investments to address our aging critical infrastructure and the supply mix objectives for generation, including off-coal initiatives, and the initiation of investments in support of the GEA.

The rate decisions support the maintenance and investment requirements of the distribution system, including those to enable the safe and reliable delivery of electricity to our customers throughout Ontario and those to support renewable distributed generation. A smarter grid for distribution will further facilitate investment in renewable sources of power generation which provide clean energy sources, reducing reliance on carbon-based fuels.

QUARTERLY RESULTS OF OPERATIONS

The following table sets forth unaudited quarterly information for each of the eight quarters from September 30, 2009 through June 30, 2011. This information has been derived from our unaudited interim Consolidated Financial Statements which, in the opinion of our management, have been prepared on a basis consistent with the audited annual Consolidated Financial Statements and which include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

(Canadian dollars in millions)	2011			2010				2009
Quarter ended	**Jun. 30**	**Mar. 31**	**Dec. 31**	**Sep. 30**	**Jun. 30**	**Mar. 31**	**Dec. 31**	**Sep. 30**
Total revenue[1]	1,268	1,460	1,280	1,360	1,165	1,319	1,207	1,144
Net income[1]	142	212	99	218	105	169	111	100
Net income to common shareholder[1]	137	208	94	214	100	165	106	96

[1] The demand for electricity generally follows normal weather-related variations, and therefore our electricity-related revenues and profit, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

LIQUIDITY AND CAPITAL RESOURCES

Our primary sources of liquidity and capital resources are funds generated from operations, debt capital market borrowings and bank financing. These resources will be used to satisfy our capital resource requirements, which continue to include capital expenditures, servicing and repayment of our debt, payments related to our outsourcing arrangements, other investing activities, and dividends.

Summary of Sources and Uses of Cash	Three months ended June 30		Six months ended June 30	
(Canadian dollars in millions)	2011	2010	2011	2010
Operating activities	334	257	574	544
Financing activities				
Long-term debt issued	-	-	300	1,000
Long-term debt retired	-	(400)	(250)	(400)
Short-term notes payable	-	-	-	(55)
Dividends paid	(42)	(5)	(84)	(19)
Investing activities				
Capital expenditures	(345)	(383)	(640)	(705)
Long-term investment[1]	-	-	-	(250)
Other financing and investing activities	10	12	13	19
Net change in cash and cash equivalents	(43)	(519)	(87)	134

[1] Represents $250 million of Province of Ontario Floating Rate Notes.

Operating Activities

Net cash from operating activities increased by $77 million, to $334 million in the second quarter, and by $30 million to $574 million in the first six months, compared to 2010. The increases in both the quarter and year-to-date periods were primarily due to higher net income compared to the prior year and changes to certain regulatory account balances. On a year-to-date basis, the impact of the increase was partially offset by growth in accounts receivable balances in the first quarter of the year resulting from higher revenues reflecting the two OEB decisions on distribution tariff rates.

Financing Activities

Short-term liquidity is provided through funds from operations, our Commercial Paper Program under which we are authorized to issue up to $1,000 million in short-term notes with a term to maturity of less than 365 days, our revolving credit facility and through our holding of Province of Ontario Floating Rate Notes.

The Commercial Paper Program is supported by a total of $1,500 million in liquidity facilities comprised of our $1,250 million committed revolving credit facility with a syndicate of banks and our holding of $250 million of Province of Ontario Floating Rate Notes. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements. On April 1, 2011, the term of the $1,250 million credit facility was extended from June 2013 to June 2014.

As at June 30, 2011, we had $7,825 million in long-term debt outstanding, including the current portion. Our notes and debentures mature between 2011 and 2046. Long-term financing is provided by our access to the debt markets, primarily through our Medium-Term Note (MTN) Program. The maximum authorized principal amount of medium-term notes issuable under this program until August 2011 is $3,000 million, of which $950 million was remaining and available as at June 30, 2011.

	Rating	
Rating Agency	**Short-term Debt**	**Long-term Debt**
DBRS Limited	R-1 (middle)	A (high)
Moody's Investors Service Inc.	Prime-1	Aa3
S&P	A-1	A+

We have the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets and impose a

negative pledge provision, subject to customary exceptions. The credit agreements related to our credit facilities have no material adverse change clauses that could trigger default. However, the credit agreements require that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreements also provide limitations that debt cannot exceed 75% of total capitalization and that debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We are in compliance with all these covenants and limitations as of June 30, 2011.

In the first six months of 2011, we issued $300 million in long-term debt under our MTN Program and repaid $250 million in maturing long-term debt, all in the first quarter. In the first six months of 2010, we issued $1,000 million in long-term debt under our MTN Program, all in the first quarter, and made second quarter repayments of $400 million in maturing long-term debt. In the first six months of 2011, we did not issue any short-term notes and there were no short-term notes outstanding as at June 30, 2011. In the first six months of 2010, we reduced our short-term notes by $55 million, all in the first quarter.

Common dividends are declared at the sole discretion of our Board of Directors, and are recommended by management based on results of operations, maintenance of the deemed regulatory capital structure, financial condition, cash requirements, and other relevant factors such as industry practice and shareholder expectations. Common dividends pertaining to the quarterly financial results are generally declared and paid in the immediately following quarter.

Consistent with the comparative periods in the prior year, we paid preferred dividends of about $5 million to the Province of Ontario (Province) in the second quarter and $9 million in the first six months. We also paid common dividends of $37 million in the second quarter and $75 million in the first six months of this year. In the first half of 2010, we paid common dividends of $10 million, all in the first quarter.

Our objectives with respect to our capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. In order to ensure ongoing effective access to capital, we target to maintain an "A" category long-term credit rating.

Investing Activities

Cash used for investing activities primarily represents capital expenditures for each of our three business segments as follows:

	Three months ended June 30				Six months ended June 30			
(Canadian dollars in millions)	**2011**	**2010**	**$ Change**	**% Change**	**2011**	**2010**	**$ Change**	**% Change**
Transmission	189	209	(20)	(10)	361	404	(43)	(11)
Distribution	155	174	(19)	(11)	278	300	(22)	(7)
Other	1	-	1	100	1	1	-	-
	345	383	(38)	(10)	640	705	(65)	(9)

Transmission

Transmission capital expenditures decreased by $20 million, or 10%, to $189 million in the second quarter, and decreased by $43 million, or 11%, to $361 million in the first six months, compared to the same periods in 2010.

Investments to expand and reinforce our transmission system were $93 million in the quarter and $183 million for the first six months of the year, representing reductions of $11 million and $28 million over the respective comparable periods. The majority of our expenditures were made on inter-area network projects to support the Province's supply mix objectives for generation, although we continue to make significant investments on load customer connection and local area supply projects to address growing loads. The year-over-year reduction in our expenditures results from the completion of several large projects in 2010. Major inter-area network projects completed and put into service last year included the installation of capacitor banks in Southwestern Ontario and our Cherrywood Transformer Station to Claireville Transformer Station Connection Project. Local area supply projects that were substantially completed in the first quarter of last year included our GTA West Transmission Reinforcement Project and our Hurontario Transformer Station to Jim Yarrow Municipal Transformer Station connection. The impact of the reductions in expenditures in both periods was partially offset by an increase in our investments this year in a number of load customer connection projects.

Our significant inter-area network upgrade projects active in the first six months of 2011 included our Bruce to Milton Transmission Reinforcement Project to connect refurbished nuclear and new wind generation sources in the Huron-Grey-Bruce area. We are currently in the testing phase of installing static var compensators (SVCs) at our Nanticoke and Detweiler transformer stations. In the short term, this project will support increased generation from the Bruce Nuclear facility and in the longer term it will enhance the transfer capability between Southwestern Ontario and the Greater Toronto Area. In addition, we are currently in the commissioning stages of installing an SVC at our Kirkland Lake Transformer Station as part of our project to install SVCs at our Porcupine and Kirkland Lake transformer stations. This project will increase the North-South interface transfer capability to access available northern generation.

Our local area supply project expenditures include investments in our Woodstock Area Transmission Reinforcement Project to increase capacity and ensure supply reliability in the Woodstock area and the Switchyard Reconstruction Project at our Burlington Transformer Station, which will address aging infrastructure and increase the load supply capacity to ensure reliability of supply to customers in the area.

Capital expenditures to sustain our existing transmission system were $88 million in the quarter and $161 million on a year-to-date basis, representing decreases of $10 million and $17 million respectively compared to the same periods last year. These reductions were primarily related to lower line requirements reflecting a lower demand for equipment replacements. The decreases were also attributable to lower expenditures to enhance security infrastructure related to the prevention of copper theft as work re-commenced in the middle of the second quarter. Our other transmission capital expenditures were $8 million in the quarter and $17 million for the first six months, representing minor increases of $1 million and $2 over the comparative periods.

Distribution

Distribution capital expenditures decreased by $19 million, or 11%, to $155 million in the second quarter and by $22 million, or 7%, to $278 million for the first six months, compared to the prior year.

Capital investments to expand and reinforce our distribution network were $68 million in the quarter and $131 million for the first six months of the year, representing reductions of $20 million and $28 million over the comparable periods. We experienced reductions in both periods related to the substantial completion of smart meter installations in 2010. During the year, we continued to invest in our smart meter network infrastructure and the development and integration of the systems required for time-of-use billing, including meter reading capability and integration with the IESO meter data repository. Of our 1.3 million customers with meters installed as at June 30, 2011, we had over 1 million consuming power based on time-of-use pricing, one of the few local distribution utilities to meet its OEB commitment. We also continued to invest in our Smart Grid Program that will enhance our operations and support distributed generation.

Expenditures to sustain our distribution system were $66 million in the quarter and $113 million year-to-date, representing marginal increases of $2 million and $3 million compared to the same periods last year. During the second quarter and year-to-date periods, we experienced increased expenditures for storm restoration work as a result of two major storms that hit Ontario on April 28 and June 8, 2011. The storms adversely impacted over 175,000 and 150,000 of our customers, respectively. Partially offsetting these impacts were lower expenditures related to wood pole replacements and reduced work related to joint use and relocation of our lines. Our other distribution capital expenditures were $21 million in the quarter and $34 million for the first six months, respectively representing a reduction of $1 million and an increase of $3 million.

Future Capital Expenditures

Our capital expenditures in 2011 are budgeted at approximately $1.8 billion. The 2011 capital budgets for our Transmission and Distribution businesses are about $1,050 million and $750 million, respectively. Capital expenditures are expected to be approximately $1.9 billion in 2012 and approximately $1.8 billion in 2013. These expenditures reflect the sustainment requirements of our aging infrastructure, budgeted at approximately $550 million in 2011, $700 million in 2012 and $700 million in 2013. Development projects, including Smart Grid, inter-area network upgrades that reflect supply mix policies to phase out coal generation, local area supply requirements and requirements to enable distributed generation, are budgeted at approximately $950 million in 2011, $950 million in 2012 and $850 million in 2013. These development investments also reflect customer demand work, distributed generation connections and the rollout of Smart Grid. Other budgeted capital expenditures amount to approximately $300 million in 2011, $250 million in 2012 and $250 million in 2013. These expenditures include the replacement of our customer billing system to address end-of-life requirements and to further productivity realization from our entity-wide SAP platform. Our capital expenditures for 2011 are expected to be lower than

budget by approximately $200 million, primarily due to changes in the cost and timing of certain large transmission projects, as well as lower Distributed Generation capital expenditures as a result of lower than anticipated proponent applications received by our Company and also higher than anticipated generator-funded investments.

On December 22, 2010, we received a letter from the Minister of Energy requesting us to proceed with the necessary planning and development work for specified transmission projects and upgrades to safely and reliably accommodate additional renewable energy. While our current budget does not include the estimated capital expenditures associated with these projects and upgrades to the system, they could be up to approximately $1 billion over a period to the in-service dates of these projects. On February 28, 2011, the OEB amended Hydro One Networks' transmission licence in accordance with a directive from the Minister of Energy to the OEB. The licence amendment requires Hydro One Networks to develop and seek approvals for these projects in accordance with recommendations from the Ontario Power Authority (OPA). In a letter dated April 7, 2011, the OPA provided the scope and timing to increase short circuit and/or transformer capacity at 10 of 15 transformer stations noted in the licence to accommodate small scale renewable generation. The overall capital cost for the 10 stations provided by the OPA in its April 7 letter is estimated to be approximately $50 million and the projected in-service dates range from August 2011 to June 2012. On June 30, 2011, we received a letter from the OPA recommending scope and timing to reconductor two circuits between Sarnia to London, the West of London Transmission Upgrade Project, to enable the connection of approximately 300-500 MW of additional renewable generation in the west of London area with a required in-service date of December 2014. We are awaiting an OPA recommendation regarding the construction of a new transmission line west of the City of London.

In accordance with the Memorandum of Agreement between Her Majesty the Queen in Right of the Province of Ontario as represented by the Minister of Energy (the Shareholder) and our Company, the Shareholder made a declaration, dated April 19, 2011, pursuant to subsection 108 (3) of the *Business Corporations Act (Ontario)* pertaining to the cost recovery of the expenditures related to the February 28, 2011 licence condition amendment. Specifically, the rights, powers and duties of our Company's Directors have been restricted with regard to any decisions regarding: the pursuit of cost recovery by Hydro One Networks from microFIT and small-scale (capacity allocation exempt) FIT generation projects or proponents thereof for costs related to investment and expenditures made, or required to be made, by Hydro One Networks in order to appropriately fund the upgrades at up to 15 transformer stations pursuant to the February 28, 2011 licence condition amendment made to Hydro One Networks' transmission licence; the pursuit of cost recovery by Hydro One Networks of such costs through regulatory processes designed to ultimately recover costs from Ontario electricity consumers through electricity rates; and whether or not to pursue and implement, internal cost recovery or cost mitigation measures designed to offset the costs associated with the upgrades, and to pursue further cost minimization strategies and to increase overall cost efficiencies within our Company, including the timing of any such decisions. In 2011, we anticipate spending approximately $25 million on these projects, which would be charged to operations. The after-tax impact on operations would be approximately $18 million.

In August 2010, the OEB introduced competition for transmission expansion projects. As a result, we did not include in our budgeted capital expenditures any projects that could meet the definition of expansion under the OEB's competitive framework. The items noted above will be considered in our upcoming budgeting process for the 2012 through 2014 period. We will not undertake large capital expenditures without a reasonable expectation of recovering them in our rates, with the exception of the 10 transformer station upgrades noted above.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations as well as other major commercial commitments.

June 30, 2011 (Canadian dollars in millions)	**Total**	**2011**[1]	**2012/2013**	**2014/2015**	**After 2015**
Contractual Obligations *(due by year)*					
Long-term debt – principal repayments	7,825	250	1,200	1,300	5,075
Long-term debt – interest payments	6,428	204	747	629	4,848
Inergi LP (Inergi) outsourcing agreement[2]	488	70	269	149	-
Operating lease commitments	51	3	14	9	25
Environmental obligations[3]	384	14	61	73	236
Total Contractual Obligations	15,176	541	2,291	2,160	10,184

Other Commercial Commitments *(by year of expiry)*	Total	2011[1]	2012/2013	2014/2015	After 2015
Bank line[4]	1,250	-	-	1,250	-
Letters of credit[5]	114	113	1	-	-
Guarantees[5]	326	326	-	-	-
Pension[6]	233	71	162	-	-
Total Other Commercial Commitments	1,923	510	163	1,250	-

[1] The amounts disclosed represent the balances due over the period July 1, 2011 to December 31, 2011.

[2] On May 1, 2010, we extended our Master Services Agreement with Inergi for a further three-year period. The term of the agreement, which would otherwise have expired on February 29, 2012, has been extended to February 28, 2015. Under the extended agreement, Inergi will provide business processing and information technology outsourcing services, as well as core system support related primarily to SAP implementation and optimization. The amounts disclosed include an estimated annual inflation adjustment in the range of 1.8% to 3.0%.

[3] We record a liability for the estimated future expenditures associated with the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated insulating oil from electrical equipment and for the assessment and remediation of contaminated lands, as well as asset retirement obligations for the removal of asbestos-contaminated material from our facilities and the decommissioning and removal of our switching station located at Ontario Power Generation's Abitibi Canyon Generating Station. The expenditure pattern reflects our planned work programs for the periods.

[4] As a backstop to our commercial paper program, we have a $1,250 million revolving standby credit facility with a syndicate of banks that matures in June 2013. On April 1, 2011 the term of this facility was extended from June 2013 to June 2014.

[5] We currently have outstanding bank letters of credit of $113 million relating to retirement compensation arrangements (RCAs). The other $1 million included in letters of credit pertains to operating letters of credit. We have also provided prudential support to the IESO on behalf of our subsidiaries as required by the IESO's Market Rules, using parental guarantees of up to a maximum of $325 million and on behalf of two distributors using guarantees of up to a maximum of $660 thousand. Although no letters of credit are required for prudential support, we would have to resume providing bank letters of credit if our credit rating deteriorated to below the "Aa" category.

[6] Contributions to the pension fund are made one month in arrears. Contributions for 2011 are based on an actuarial valuation filed in September 2010 and effective December 31, 2009. Our annual pension contributions for 2011 and 2012 will depend on future investment returns, changes in benefits or actuarial assumptions. Based on current factors, we estimate our minimum pension contributions to be approximately $145 million in 2011 and $149 million in 2012 based on the expected level of pensionable earnings. Contributions for 2013 will be based on a new actuarial valuation effective December 31, 2012.

The amounts in the above table under long-term debt – principal repayments are not charged to our results of operations, but are reflected on our Consolidated Balance Sheet and Consolidated Statement of Cash Flows. Interest associated with this debt is recorded under financing charges on our Consolidated Statement of Operations or in our capital programs. Payments in respect of operating leases and our outsourcing agreement with Inergi are recorded under operation, maintenance and administration expense on our Consolidated Statement of Operations or within our capital expenditures. Expenditures related to our environmental programs and asset retirement obligations are not charged to our results of operations, but are reflected on our Consolidated Balance Sheet and Consolidated Statement of Cash Flows.

RELATED PARTY TRANSACTIONS

Related party transactions primarily consist of our transmission revenues received from, and our power purchases payments made to, the IESO, which is a related party by virtue of its status as an agency of our shareholder, the Province. The year-over-year changes related to these amounts are described more fully in our discussion of our transmission revenues and purchased power costs. Other significant related party transactions include our dividends which are paid to the Province and our payments in lieu of corporate income taxes which are paid or payable to the Ontario Electricity Financial Corporation. In January 2010, we purchased $250 million of Province of Ontario Floating Rate Notes, maturing on November 19, 2014, as a form of alternate liquidity to supplement our bank credit facilities.

CONSIDERATIONS OF CURRENT ECONOMIC CONDITIONS

Pension

During the first six months of 2011, the deferred pension asset reported on our Consolidated Balance Sheet increased by $4 million to $464 million. We contributed $78 million into our pension plan and incurred $74 million in net periodic pension benefit cost. Contributions for 2011 and 2012 are based on an actuarial valuation effective December 31, 2009 that was filed in September of 2010. Based on current factors, we currently estimate our annual pension contributions to be approximately

$145 million in 2011 and $149 million in 2012 based on the projected level of pensionable earnings. Contributions for 2013 will be based on an actuarial valuation effective December 31, 2012 and will depend on future investment returns, changes in benefits and actuarial assumptions.

Our pension plan experienced a positive return of 2.19% in the first six months of this year. Consistent with other pension plans, our pension plan could be negatively impacted during the remainder of the year as a result of the current economic uncertainty and financial market volatility. However, our fund continues to recover and experience positive returns. The overall return for 2010 was approximately 9.96%.

The pension fund has broad exposure from its investments in domestic and international equity markets, as well as in fixed income markets. The overall exposure of the fund reflects its holdings across a number of sectors, and a well-diversified portfolio to support long-term objectives.

We continue to monitor our financial risks, including credit risk.

STATUS OF OUR TRANSITION TO UNITED STATES (US) GENERALLY ACCEPTED ACCOUNTING PRINCIPLES (GAAP)

Accounting Framework for External Reporting

We previously planned to adopt International Financial Reporting Standards (IFRS) effective January 1, 2012 with comparative restatement of our 2011 results. In the absence of a definitive International Accounting Standards Board (IASB) plan to provide guidance on rate-regulated accounting, in the first quarter of this year we began evaluating the option of adopting US GAAP in lieu of IFRS. On July 7, 2011, we filed our application with the Ontario Securities Commission (OSC) for exemptive relief from the requirements of section 3.2 of National Instrument 52-107 *Acceptable Accounting Policies and Auditing Standards* that would otherwise require us to file our consolidated financial statements based on IFRS starting with reporting periods commencing after January 1, 2012. Our application requested approval to instead adopt US GAAP, without becoming a Securities and Exchange Commission registrant, for our 2012, 2013 and 2014 fiscal years. On July 21, 2011, the OSC approved our application and granted us the requested exemptive relief. Our Board of Directors has approved a resolution authorizing us to report under US GAAP. Under US GAAP, our financial reporting will be more stable and comparable with our current Canadian GAAP results than it would have been under IFRS. The use of US GAAP will also facilitate benchmarking to other large North American utilities in terms of our securities, as well as cost comparisons for the OEB. Our March 31, 2012 consolidated financial statements will be prepared based on US GAAP with two years of comparative restatement of the amounts recorded on the opening US GAAP Consolidated Balance Sheet as at January 1, 2010. As a result of this decision, our IFRS conversion project efforts have been reduced. However, our work will be managed in such a way that it can effectively be restarted if a future transition to IFRS is required.

In anticipation of OSC approval of our application, we initiated a US GAAP conversion project that consists of three phases: scoping and diagnostic; analysis; and implementation. The scoping and diagnostic phase of our project involved a high level review of the major differences between existing Canadian and US GAAP. We completed this phase in the second quarter. We also substantially completed the second or analytical phase of our project in the quarter. This phase involved assessment of the impacts of adopting US GAAP on our consolidated financial statements, including measurement, classification, presentation and disclosure. The differences identified to date include a change to the presentation of preferred shares on the balance sheet and adjustments related to employee benefit costs. Our preferred shares, which are held entirely by the Province of Ontario, will be classified as mezzanine equity under US GAAP. In accordance with OEB rate orders, pension costs are recorded under Canadian GAAP when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Pension costs will be recorded in the same way under US GAAP. Employee future benefits other than pension are, and will continue to be recorded on an accrual basis. There are minor differences between Canadian and US GAAP for certain employee future benefits costs. However, we do not expect any significant change to the net asset position on our Consolidated Balance Sheet. Nor do we expect significant impacts on our Consolidated Statement of Operations following the application of US GAAP to our employee future benefits costs.

Over the remainder of this year, we will continue to assess and refine the impact that the conversion will have upon our disclosures.

Accounting Framework for Rate Making

Coincident with our OSC application, on July 15, 2011, we applied to the OEB for permission to adopt US GAAP instead of modified IFRS as the basis for our future rate applications and for our ongoing regulatory accounting and reporting for the Distribution Business of our subsidiary Hydro One Networks. On the same date, we also tabled a motion with the OEB requesting a variance to its December 23, 2010 decision on the transmission revenue requirement and rates of Hydro One Networks. The motion proposes that the OEB approve the use of US GAAP in place of modified IFRS for rate-setting purposes effective January 1, 2012 and that our approved 2012 revenue requirement be reduced to reflect differences between US GAAP and modified IFRS with respect to which overhead and indirect costs qualify for capitalization. We expect that the OEB will provide its decisions on these two applications prior to December 31, 2011, in which case our future capital expenditure amounts would remain consistent with our plan.

Debt Covenants

We have the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization. As part of our US GAAP transition, we have analyzed the impact of potential accounting changes on our debt covenants. Based on the work performed in phases one and two of our project, after conversion to US GAAP we expect to remain in compliance with these covenants. We have also amended our bond indentures allowing us to use US GAAP for reporting purposes.

Internal Control over Financial Reporting and Disclosure Controls and Procedures

We have assessed the impact of conversion on our internal controls over financial reporting and on our disclosure controls and procedures. We do not anticipate any changes to existing controls or a need for additional controls as a result of conversion from Canadian GAAP to US GAAP.

Financial Reporting Expertise

Given the similarities between US GAAP and current Canadian GAAP, our US GAAP training efforts are focused on specific areas of difference between the two accounting frameworks and these efforts are initially being targeted to specific staff. In the fourth quarter of this year and in the first quarter of 2012, additional formal training will be provided to other finance and operational staff who are not directly involved in our conversion project. In addition, training will be provided to the Audit and Finance Committee of our Board of Directors as well as to senior executive management. This training will concentrate on communicating the key differences between Canadian and US GAAP at a level of detail that is appropriate to meet their respective needs.

Information Technology (IT) Systems

We have completed a preliminary assessment of the impacts from converting to US GAAP on our IT systems. Our recently implemented SAP enterprise systems allow for flexibility in the application of accounting policies and, given the similarities between Canadian and US GAAP, we anticipate that any required IT system changes to accommodate US GAAP will be comparatively minimal. Our systems have been designed to be sufficiently flexible as to allow the future adoption of IFRS should this be required.

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Our Supply Chain Enhancement Project to develop an operating framework that outlines the strategy and objectives of supply chain was implemented in the second quarter. The resulting new processes have been reviewed to assess the impact on the control environment. Process documents are updated and controls will be tested for design and operating effectiveness throughout the remainder of this year.

In an effort to optimize our customer service operations, we have initiated our Customer Information System (CIS) Project. CIS will replace two applications currently in use to provide billing, customer contact, field services, settlements and customer choice administration to our distribution customers and key constituents. The project, which was approved in the second quarter, is planned to go-live in the fourth quarter of 2012. The CIS project is currently in the design phase during which CIS processes will be reviewed and analyzed to ensure that key risks remain adequately addressed by our internal controls.

In compliance with the requirements of National Instrument 52-109, *Certification of Disclosure in Issuers' Annual and Interim Filings*, our Certifying Officers have reviewed and certified the Consolidated Financial Statements for the interim period ended June 30, 2011, together with other financial information included in our quarterly securities filings. Our Certifying Officers have also certified that disclosure controls and procedures have been designed to provide reasonable assurance that material information relating to our Company is made known within our Company. Further, our Certifying Officers have also certified that internal controls over financial reporting have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements.

RECENT DEVELOPMENTS

West of London Transmission Upgrade Project

On June 30, 2011, we received a letter from the OPA providing us with a recommendation on the scope and timing of one of the three projects specified in the December 22, 2010 letter from the Minister of Energy. The OPA has recommended that the West of London Transmission Upgrade Project proceed to enable the connection of approximately 300-500 MW of additional renewable generation in the west of London area. The required in-service date for the upgrade is December 2014.

Collective Bargaining Agreements

On June 3, 2011, the membership of the Power Worker's Union ratified the settlement with our Company that was reached on March 23, 2011. The settlement had been previously approved by our Board of Directors.

On June 14, 2011, the International Brotherhood of Electrical Workers' membership ratified an agreement with our subsidiary, Hydro One Brampton Networks Inc. (Hydro One Brampton). The agreement was approved by the Board of Directors of Hydro One Brampton on June 10, 2011.

Integrated Power System Plan (IPSP)

On May 9, 2011 the OPA announced that it was beginning consultations to update Ontario's IPSP and issued the *IPSP Planning and Consultation Overview* document. A series of four consultation sessions occurred during the month of May. The OPA asked stakeholders to provide input into the IPSP by June 17, 2011. We submitted our comments on that day. Stakeholder comments will form part of the evidence when the OPA submits the revised IPSP to the OEB for review.

Bruce to Milton Transmission Reinforcement Project

On May 13, 2011, we received a decision rendered by the Minister of Natural Resources, directing the Niagara Escarpment Commission to issue to our Company a Development Permit for our work on the Niagara Escarpment portion of the Bruce to Milton line, provided that we meet certain conditions. Those conditions are virtually unchanged from the conditions that accompanied the Development Permit initially issued to our Company and which was the subject matter of an appeal by certain parties. On July 4, 2011, we celebrated the mid-point of construction of the line, which is anticipated to be in-service by December 2012.

SELECTED FINANCIAL HIGHLIGHTS AND RATIOS

	Three months ended June 30		Six months ended June 30	
(Canadian dollars in millions) (except as otherwise noted)	**2011**	**2010**	**2011**	**2010**
Net income	142	105	354	274
Net cash from operating activities	334	257	574	544
Capital expenditures	345	383	640	705
Basic and fully diluted earnings per common share *(Canadian dollars)*	1.375	1.005	3.451	2.655
Earnings coverage ratio[1]			2.65	2.15
Net asset coverage on long-term debt[2]			1.80	1.77
Total debt to capitalization[3]			56%	57%

[1] The earnings coverage ratio has been presented for the twelve months ended June 30, 2011 and June 30, 2010, respectively and has been calculated as the sum of net income, provision for payments in lieu of corporate income taxes and financing charges divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

[2] The net asset coverage on long-term debt ratio has been presented as at June 30, 2011 and December 31, 2010 and has been calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt (including current portion).

[3] Total debt to capitalization ratio has been presented as at June 30, 2011 and December 31, 2010 and has been calculated as total debt divided by total debt plus total shareholder's equity.

FORWARD-LOOKING STATEMENTS AND INFORMATION

Our oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate and include beliefs and assumptions made by the management of our company. Such statements include, but are not limited to: expectations regarding energy related revenues and profit; expectations regarding developments in the statutory and operating framework for electricity distribution and transmission in Ontario including the impacts of decisions from the OEB and other governing bodies; statements related to the status of our applications to the OEB; expectations regarding revenue from our rates including the application of such revenues; statements regarding our future liquidity and capital resource and operating requirements; expectations regarding our financing activities; expectations regarding the results of our on-going and planned projects and/or initiatives, their expected completion dates and expected benefits; statements regarding future capital expenditures, budgets, our investment plans, project costs and expected impacts on operations; statements related to smart meters and the associated smart grid; statements related to the IPSP; statements regarding contractual obligations and other commercial commitments; statements about our outsourcing arrangement with Inergi LP; statements regarding the amount and timing of future estimated environmental expenditures; statements regarding future pension contributions and our pension plan and actuarial valuation; statements about IFRS and IASB and planned courses of action; statements regarding US GAAP, planned courses of action and expected impacts on our disclosures, internal controls and systems; and statements related to our debt covenants. Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "aim", "target", and "continue", and variations of such words and similar expressions, are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; no unfavourable decisions from the OEB and other regulatory bodies concerning outstanding applications; no unforeseen changes in rate orders or rate structures for our distribution and transmission businesses; a stable regulatory environment; the current application of Canadian GAAP for rate-regulated activities will generally be consistent with US GAAP; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to us, including information obtained from third party industry analysts. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- the risks associated with being controlled by the Province including the possibility that the Province may make declarations pursuant to our memorandum of agreement with it;
- the risk that unexpected capital expenditures may be needed to support renewable generation or resolve unforeseen technical issues;
- on-going discussions with the OPA regarding transmission project needs and priorities and distributed generation requirements;
- any opposition to and delays or denials of the requisite approvals and accommodations for our planned projects;
- the result of regulatory decisions regarding our revenue requirements, cost recovery and rates;

- investment returns, changes in benefits or actuarial assumptions;
- the risk associated with being subject to extensive regulation including risks associated with OEB action or inaction;
- the risk that previously granted regulatory approvals may be subsequently challenged, appealed or overturned;
- unanticipated changes in our costs;
- the potential for substantial and currently undetermined or underestimated environmental costs and liabilities or that assumptions that form the basis of our recorded environmental liabilities and related regulatory assets may change;
- the result of regulatory decisions regarding our accounting framework for rate making;
- the risks associated with changes in interest rates;
- the risks associated with current economic uncertainty and financial market volatility;
- the impact of the GEA on our company and the costs and expenses arising there from; and
- the impact of increased competition on our transmission business.

We caution the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail under "Risk Management and Risk Factors" in the 2010 annual Management's Discussion and Analysis (MD&A). You should review the section entitled "Risk Management and Risk Factors" in detail.

This MD&A is dated as at August 11, 2011. Additional information about our company, including our Annual Information Form, is available on SEDAR at www.sedar.com.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (unaudited)

(Canadian dollars in millions)	Three months ended June 30		Six months ended June 30	
	2011	**2010**	**2011**	**2010**
Revenues				
Transmission	337	306	688	626
Distribution	915	842	2,008	1,825
Other	16	17	32	33
	1,268	1,165	2,728	2,484
Costs				
Purchased power	587	542	1,306	1,197
Operation, maintenance and administration	275	266	537	524
Depreciation and amortization	151	144	295	283
	1,013	952	2,138	2,004
Income before financing charges and provision for payments in lieu of corporate income taxes	255	213	590	480
Financing charges	86	88	170	173
Income before provision for payments in lieu of corporate income taxes	169	125	420	307
Provision for payments in lieu of corporate income taxes	27	20	66	33
Net income	142	105	354	274
Other comprehensive loss	-	-	-	-
Comprehensive income	142	105	354	274
Basic and fully diluted earnings per common share *(Canadian dollars)*	1.375	1.005	3.451	2.655

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (unaudited)

(Canadian dollars in millions)	Three months ended June 30		Six months ended June 30	
	2011	**2010**	**2011**	**2010**
Retained earnings, beginning of period	2,524	1,946	2,354	1,791
Net income	142	105	354	274
Dividends *(Note 3)*	(42)	(5)	(84)	(19)
Retained earnings, end of period	2,624	2,046	2,624	2,046

CONSOLIDATED STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE LOSS (unaudited)

(Canadian dollars in millions)	Three months ended June 30		Six months ended June 30	
	2011	**2010**	**2011**	**2010**
Accumulated other comprehensive loss, beginning of period	(10)	(10)	(10)	(10)
Other comprehensive loss	-	-	-	-
Accumulated other comprehensive loss, end of period	(10)	(10)	(10)	(10)

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (unaudited)

(Canadian dollars in millions)	June 30, 2011	December 31, 2010
Assets		
Current assets:		
Cash	-	33
Short-term investments	118	139
Accounts receivable (net of allowance for doubtful accounts)	977	911
Regulatory assets	29	42
Materials and supplies	22	21
Future income tax assets	28	35
Other	13	8
	1,187	1,189
Fixed assets:		
Fixed assets in service	20,124	19,767
Less: accumulated depreciation	7,470	7,247
	12,654	12,520
Construction in progress	1,621	1,394
Future use land, components and spares	140	139
	14,415	14,053
Other long-term assets:		
Regulatory assets	1,070	1,013
Deferred pension asset	464	460
Long-term investment	250	249
Intangible assets (net of accumulated amortization)	207	197
Goodwill	133	133
Future income tax assets	18	19
Other	14	9
	2,156	2,080
Total assets	17,758	17,322

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (unaudited) (continued)

(Canadian dollars in millions)	June 30, 2011	December 31, 2010
Liabilities		
Current liabilities:		
Bank indebtedness	33	-
Accounts payable and accrued charges	857	884
Regulatory liabilities	32	72
Accrued interest	82	84
Long-term debt payable within one year *(Note 4)*	250	500
	1,254	1,540
Long-term debt *(Note 4)*	7,581	7,278
Other long-term liabilities:		
Employee future benefits other than pension	1,014	980
Regulatory liabilities	601	540
Future income tax liabilities	751	693
Environmental liabilities	283	287
Asset retirement obligations	11	11
Long-term accounts payable and other liabilities	12	12
	2,672	2,523
Total liabilities	11,507	11,341
Shareholder's equity		
Preferred shares (authorized: unlimited; issued: 12,920,000)	323	323
Common shares (authorized: unlimited; issued: 100,000)	3,314	3,314
Retained earnings	2,624	2,354
Accumulated other comprehensive loss	(10)	(10)
Total shareholder's equity	6,251	5,981
Total liabilities and shareholder's equity	17,758	17,322

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

(Canadian dollars in millions)	Three months ended June 30		Six months ended June 30	
	2011	**2010**	**2011**	**2010**
Operating activities				
Net income	142	105	354	274
Environmental expenditures	(3)	(5)	(7)	(8)
Adjustments for non-cash items:				
Depreciation and amortization (excluding removal costs)	132	129	263	257
Regulatory asset and liability accounts	10	(4)	36	(7)
Future income taxes	1	4	3	13
Other	-	2	(1)	2
	282	231	648	531
Changes in non-cash balances related to operations	52	26	(74)	13
Net cash from operating activities	334	257	574	544
Financing activities				
Long-term debt issued	-	-	300	1,000
Long-term debt retired	-	(400)	(250)	(400)
Short-term notes payable	-	-	-	(55)
Dividends paid	(42)	(5)	(84)	(19)
Other	-	-	(2)	-
Net cash (used in) from financing activities	(42)	(405)	(36)	526
Investing activities				
Capital expenditures				
Fixed assets	(327)	(379)	(604)	(696)
Intangible assets	(18)	(4)	(36)	(9)
	(345)	(383)	(640)	(705)
Long-term investment	-	-	-	(250)
Other assets	10	12	15	19
Net cash used in investing activities	(335)	(371)	(625)	(936)
Net change in cash and cash equivalents	(43)	(519)	(87)	134
Cash and cash equivalents, beginning of period *(Note 6)*	128	627	172	(26)
Cash and cash equivalents, end of period	85	108	85	108

See accompanying notes to Consolidated Financial Statements.

1. BASIS OF PRESENTATION

These interim Consolidated Financial Statements do not conform in all respects to the disclosure requirements of Canadian generally accepted accounting principles (GAAP) for annual financial statements and should, therefore, be read in conjunction with the annual Consolidated Financial Statements of Hydro One Inc. (Hydro One or the Company) for the year ending December 31, 2010 which include information necessary or useful to understanding the Company's business and financial statement presentation. In particular, the Company's significant accounting policies and practices are presented as Note 2 to the annual Consolidated Financial Statements, and have been consistently applied in the preparation of these interim Consolidated Financial Statements.

The demand for electricity generally follows normal weather-related variations, and therefore the Company's energy-related revenues, all other things being equal, will tend to be higher in the first and third quarters than in the second and fourth quarters.

2. ACCOUNTING CHANGES

Emerging Accounting Changes

United States (US) GAAP

The Company previously anticipated it would apply International Financial Reporting Standards (IFRS) to its consolidated financial statements for fiscal periods beginning on or after January 1, 2012, with comparative restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2011. In the absence of a definitive plan for a new project to consider the issuance of a rate-regulated accounting standard by the International Accounting Standards Board, Hydro One began evaluating the option of adopting US GAAP in lieu of IFRS in the first quarter of this year. On July 7, 2011, the Company filed an application with the Ontario Securities Commission (OSC) for exemptive relief from the requirements of section 3.2 of NI 52-107 "Acceptable Accounting Policies and Auditing Standards" that would otherwise require it to file consolidated financial statements based on IFRS starting with reporting periods commencing after January 1, 2012. The Company's application requested approval to instead adopt US GAAP, without becoming a Securities and Exchange Commission registrant, for its 2012, 2013 and 2014 fiscal years. On July 21, 2011, the OSC approved the Company's application and granted it the requested exemptive relief. Hydro One's Board of Directors has approved a resolution authorizing it to report under US GAAP. As a result, the Company's March 31, 2012 consolidated financial statements will be prepared based on US GAAP with two years of comparative restatement of the amounts recorded on the opening US GAAP Consolidated Balance Sheet as at January 1, 2010. The Company anticipates that its current application of Canadian GAAP for rate-regulated activities will generally be consistent with US GAAP. Any differences between Canadian and US GAAP and their impact on the Company's consolidated financial statements will be assessed as part of the Company's US GAAP conversion project.

3. DIVIDENDS

During the three months ended June 30, 2011, preferred dividends in the amount of $5 million (2010 - $5 million) and common dividends in the amount of $37 million (2010 - $nil) were declared. During the six months ended June 30, 2011, preferred dividends in the amount of $9 million (2010 - $9 million) and common dividends in the amount of $75 million (2010 - $10 million) were declared.

4. LONG-TERM DEBT

During the six months ended June 30, 2011, Hydro One issued additional notes under the Company's Medium-Term Note Program.

On January 19, 2011, Hydro One issued additional 2.95% notes with a principal amount of $250 million under its Medium-Term Note (MTN) Program. These notes, which mature on September 11, 2015, were an additional offering of notes originally issued on September 13, 2010 for $250 million. This additional issuance brings the total amount outstanding for this issue to $500 million.

Hydro One entered into two fixed-to-floating interest-rate swaps, effective on January 19, 2011, each with a $125 million notional principal amount, to convert the $250 million notes issued on the same day into three-month variable-rate debt. The Company designated these swaps as fair value hedges of interest-rate risk. As such, changes in fair value are recognized in the Consolidated Statement of Operations for the period, as are changes in the fair value of the related fixed-rate notes. To the extent the hedge is ineffective, any ineffective amount is recorded immediately in financing charges within the Consolidated Statement of Operations. This amount was insignificant for the quarter and year-to-date periods.

On January 24, 2011, The Company issued $50 million in floating-rate notes under its MTN Program with a maturity date of July 24, 2015.

On March 22, 2011, the Company entered into five forward-rate agreements to lock-in five interest-rate resets on the floating rate it pays on $550 million of floating-rate debt, with respective settlement dates of: April 25, 2011; May 19, 2011; June 13, 2011; July 25, 2011; and August 19, 2011. On May 26, 2011, the Company entered into two more forward-rate agreements to lock-in one interest-rate reset on the floating rate it pays on $250 million of floating-rate debt with a settlement date of September 11, 2011. These agreements were classified as held-for-trading financial instruments and are measured at fair value. The cash settlements on the forward rate agreements that settled on April 25, May 19 and June 13 were not significant. As at June 30, 2011, the net fair value loss recorded on the remaining four agreements was immaterial.

5. EMPLOYEE FUTURE BENEFITS

Total benefit costs are as follows:

	Three months ended June 30		Six months ended June 30	
(Canadian dollars in millions)	**2011**	**2010**	**2011**	**2010**
Pension				
Net periodic benefit cost	37	46	74	91
Pension fund contribution	42	29	78	59
Less: Portion attributable to labour and capitalized as part of the cost of fixed assets	16	12	30	24
Charged to results of operations	26	17	48	35
Employee Future Benefits Other than Pension				
Net periodic benefit cost	27	23	54	45
Less: Portion attributable to labour and capitalized as part of the cost of fixed assets	11	9	22	18
Charged to results of operations	16	14	32	27

6. CONSOLIDATED STATEMENTS OF CASH FLOWS

For the purposes of the Consolidated Statements of Cash Flows, "cash and cash equivalents" refers to the Consolidated Balance Sheet items "cash", "short-term investments" and "bank indebtedness."

7. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The Transmission Business, which comprises the core business of providing transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- The Distribution Business, which comprises the core business of delivering and selling electricity to customers; and
- An "other" segment, the operations of which primarily consist of those of the telecommunications business.

The designation of segments has been based on a combination of regulatory status and the nature of the products and services provided. Segment information on the above basis is as follows:

Three months ended June 30 (Canadian dollars in millions)	Transmission	Distribution	Other	Consolidated
2011				
Segment profit				
Revenues	337	915	16	1,268
Purchased power	-	587	-	587
Operation, maintenance and administration	104	155	16	275
Depreciation and amortization	73	75	3	151
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	160	98	(3)	255
Financing charges				86
Income before provision for payments in lieu of corporate income taxes				169
Capital expenditures	189	155	1	345
2010				
Segment profit				
Revenues	306	842	17	1,165
Purchased power	-	542	-	542
Operation, maintenance and administration	103	148	15	266
Depreciation and amortization	66	75	3	144
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	137	77	(1)	213
Financing charges				88
Income before provision for payments in lieu of corporate income taxes				125
Capital expenditures	209	174	-	383

Six months ended June 30 (Canadian dollars in millions)	Transmission	Distribution	Other	Consolidated
2011				
Segment profit				
Revenues	688	2,008	32	2,728
Purchased power	-	1,306	-	1,306
Operation, maintenance and administration	210	297	30	537
Depreciation and amortization	145	145	5	295
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	333	260	(3)	590
Financing charges				170
Income before provision for payments in lieu of corporate income taxes				420
Capital expenditures	361	278	1	640

Six months ended June 30 (Canadian dollars in millions)	Transmission	Distribution	Other	Consolidated
2010				
Segment profit				
Revenues	626	1,825	33	2,484
Purchased power	-	1,197	-	1,197
Operation, maintenance and administration	210	285	29	524
Depreciation and amortization	130	148	5	283
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	286	195	(1)	480
Financing charges				173
Income before provision for payments in lieu of corporate income taxes				307
Capital expenditures	404	300	1	705

(Canadian dollars in millions)	June 30, 2011	December 31, 2010
Total assets		
Transmission	10,071	9,805
Distribution	7,151	6,908
Other	536	609
	17,758	17,322

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

8. SUBSEQUENT EVENT

On August 2, 2011, the Company entered into two forward-rate agreements in order to lock-in two interest-rate resets on the floating rate it pays on $165 million of floating-rate debt. Both forward-rate agreements are classified as held-for-trading and measured at fair value.

9. COMPARATIVE FIGURES

The comparative Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the June 30, 2011 Consolidated Financial Statements.